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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies.	Rulemaking 06-04-009 (Filed April 13, 2006)

COMMENTS OF THE NATURAL RESOURCES DEFENSE COUNCIL (NRDC) AND THE UNION OF CONCERNED SCIENTISTS (UCS) ON MODELING-RELATED ISSUES

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In accordance with the Commission's Rules of Practice and Procedure, the above-signed organizations respectfully submit the following comments in response to the Administrative Law Judges' (ALJ) Ruling Requesting Comments on Modeling-Related Issues dated November 9, 2007. The Natural Resources Defense Council (NRDC) and the Union of Concerned Scientists (UCS) are non-profit membership organizations with a long-standing interest in supporting cost-effective reductions in greenhouse gas emissions.

We deeply appreciate the efforts of the multi-agency staff team that has overseen this project and of the Energy and Environmental Economics (E3) staff that has developed the greenhouse gas (GHG) modeling methodology. We believe that this project will provide essential support for the development of cost-effective strategies to meet the State's GHG emission reduction goals. We offer the following comments and recommendations in an effort to improve the modeling methodology and data and make the results as useful as possible for policymakers. Our comments respond to the questions posed in the ALJ Ruling.

Q1. Does Attachment A cover all of the viable emissions reduction measures available in the electricity and natural gas sectors?

Attachment A provides a good start in listing the possible emissions reduction measures, in particular for the investor-owned utilities in the electricity sector. Our comments, below, discuss the measures for the electricity and natural gas sectors separately.

Electricity Sector

We recommend a few additions to, and offer comments on, the list provided by Attachment A:

- POU-implemented measures, including energy efficiency and renewable energy, should be included in addition to IOU-implemented measures.
- The embedded energy savings of water conservation should be included in more detail.
- Plant retirements, in addition to repowering, should be included.
- We agree with the E3 model's inclusion of CCS as a possible emission reduction measure.

POU-implemented measures

In Attachment A, the descriptions of both "Existing Control Measures" (Section 3.1) and "Further Potential" (Section 3.2) focus on the reduction measures of the investor owned utilities (IOUs) but overlook the reductions possible by the publicly owned utilities (POUs). In contrast, the E3 GHG model appropriately includes emission reduction measures for both IOUs and POUs. We urge the Commission to explicitly include discussion of opportunities for POU emission reductions in Attachment A. For example, the CEC's report, ***"****Achieving All Cost-Effective Energy Efficiency for California,"* adopted on December 19, 2007, summarizes the first comprehensive set of energy efficiency targets that California's POUs have adopted pursuant to Assembly Bill 2021 (Levine, 2006). In aggregate, these targets would more than triple the POUs' annual energy savings and we estimate that they will save the POUs' customers $2 billion on their energy bills over the next ten years.[1]

[1] Wang, D., E. Wanless, and L. Ettenson, *Analysis of California's Publicly-Owned Utilities' Ten-Year Energy Efficiency Targets,* Natural Resources Defense Council, December 17, 2007.

Embedded energy savings from water conservation

Although Attachment A mentions that the CPUC and CEC "have begun to examine the potential energy savings associated with water-use efficiency measures" (p. 6), this statement does not acknowledge the full GHG reduction potential of saving energy through increased water efficiency. NRDC estimates that increased water efficiency throughout the state could reduce the state's GHG emissions by up to 4.8 MMTCO2e from business-as-usual emissions in 2020,[2] with further savings from strategies like water recycling.

Plant retirements

Attachment A recognizes the potential of repowering old generating facilities to reduce GHG emissions (p. 9). We support the inclusion of repowering and suggest that retirement of old and high GHG-emitting plants should also be considered as a means to reduce emissions.

Carbon capture and disposal

Aggressive pursuit of all cost-effective energy efficiency and increased renewable energy must be the first priorities for reducing GHG emissions. However, other tools, such as carbon capture and sequestration (CCS) may need to be included in the toolbox to ensure our ability to meet our GHG reduction goals. Although Attachment A raises the potential for coal integrated gasification combined cycle (IGCC) technology with CCS, it then proceeds to question whether the technologies can be deployed in the 2020 timeframe.[3] Unfortunately, the statements in Attachment A do not appropriately consider the commercial track record and technical challenges of CCS when making this judgement. While it is true that only a limited number of IGCC plants exist worldwide that operate on coal, that fact alone is not a reflection of its feasibility. The key step is the

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[2] See NRDC Scoping Plan recommendation submitted to CARB, "Urban Water Use Efficiency," October 1, 2007.

[3] "Coal IGCC generation has a very limited commercial track record, with only four demonstration units in commercial operation worldwide. CCS has no track record at all in commercial operation, and faces significant technical challenges, particularly with regards to the viability of long-term storage of CO2 in geologic formations….As the likely rate of deployment of geologic CCS is probably too slow for consideration of this technology in policy decisions over the short-term through 2020, it is not examined in detail within this paper" (p. 10).

gasification, not the addition of turbines for power generation. Hundreds of industrial gasifiers operate around the world, and around 40 of them operate on coal.[4]

We believe that the main barriers for the construction of CCS plants are not technical, but economic and policy-related instead. CCS has already been demonstrated in an integrated fashion in three major international commercial projects (Sleipner, In Salah and Weyburn), all of which have been operation for years and have shown that CO2 can stay permanently sequestered underground. Several others are under development. Moreover, CCS' constituent elements of capture, transportation and sequestration/injection have also been demonstrated separately. In addition, enhanced oil recovery (EOR) has been a standard industry practice for decades, and shares much of the same fundamental engineering as CCS. Full-scale CCS at a power plant therefore only requires the stringing together of established technologies. Both the IPCC and the Massachusetts Institute of Technology (MIT) have studied CCS in depth in special reports and concluded that it is technically viable.[5] The AB 1925 CEC Report, *Geologic Carbon Sequestration Strategies for California*, echoes this view: "although technical challenges remain, the primary barriers to progressing with initial geologic sequestration projects concern economic viability and statutory and regulatory issues." (p. xi)

There are several cheaper and cleaner ways to reduce the carbon footprint of electric power generation such as increasing energy efficiency and renewable energy, and we should be maximizing those first; however, we believe that limited application of CCS is possible within the 2020 timeframe. We therefore support the inclusion of CCS in the E3 model and we urge the Commission to revise the description of CCS in Attachment A to acknowledge the potential contribution of this technology to reduce greenhouse gas emissions.[6] We also urge E3 to review and validate the CCS cost

[4] More details can be found at www.gasification.org, which has a database of projects.
[5] Intergovernmental Panel on Climate Change, *Carbon Dioxide Capture and Storage*, 2005; Massachusetts Institute of Technology, *The Future of Coal: Options for a Carbon-Constrained World*, 2007
[6] For further information on CCS, please refer to NRDC's David Hawkins' congressional testimony to Rep. Markey's Select Committee on Energy Independence and Global Warming: http://globalwarming.house.gov/tools/assets/files/0020.pdf.

estimates in their model with those in a recent report by the National Energy Technology Laboratory[7] as well as those in the MIT and AB 1925 reports referred to above.

Natural Gas Sector

The use of solar thermal for water and space heating as a replacement for natural gas is an important emission reduction measure with the technical potential to save over one billion therms of natural gas in California every year,[8] or approximately 5.3 $MMTCO_2E$ reductions.[9] Atttachment A and the E3 model should include potential emission reductions from development of this resource.

Increased use of efficient combined heat and power (CHP) can also reduce the demand for natural gas. CHP has the potential to use energy more efficiently than separate facilities to produce power and heat, and can thus reduce emissions.

Although Attachment A discusses the benefits of using biomethane to replace natural gas and the E3 model includes the potential to use biogas to generate electricity, the model does not appear to include the possible reductions that can be achieved from using biomethane (i.e., upgraded biogas) to replace natural gas. The model should include potential emission reductions from the use of biomethane to replace natural gas. We estimate that the capture and use of biomethane from California dairies can provide approximately 7.2 $MMTCO_2E$ of reductions by 2020.[10] Utilizing biomethane from wastewater treatment facilities could yield further reductions.

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[7] National Energy Technology Laboratory, *Cost and Performance Baseline forFossil Energy Plants, DOE/NETL-2007/1281, Volume 1: Bituminous Coal and Natural Gas to ElectricityFinal Report*, May 2007.

[8] National Renewable Energy Laboratory, *The Technical Potential of Solar Water Heating to Reduce Fossil Fuel Use and Greenhouse Gas Emissions in the United States*, March 2007, p.10; *See also* Environmental California Research & Policy Center, *Solar Water Heating: How California Can Reduce Its Dependence on Natural Gas*, April 2007, p.14, citing Fred Coito and Mike Rufo, KEMA-Xenergy Inc, for Pacific Gas & Electric Company, *California Statewide Residential Sector Energy Efficiency Potential Study*, April 2003 and Fred Coito and Mike Rufo, KEMA-Xenergy Inc, for Pacific Gas & Electric Company, *California Statewide Commercial Sector Natural Gas Energy Efficiency Potential Study*, May 14, 2003.

[9] California Air Resources Board, *Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report: Final Report*, October 15, 2007, p. 11, available at http://www.climatechange.ca.gov/events/2007-09-14_workshop/final_report/2007-10-15_MACROECONOMIC_ANALYSIS.PDF states that 1MMBtu = 53.06 kg CO2e (1,000 million therms * (100,000 MBtu / million therm) * (53.06 kg CO2 / MBtu) * (1 metric tons CO2 / 1,000 kg CO2) = 5,306,000 metric tons CO2)

[10] See NRDC's scoping plan recommendation, available at http://www.arb.ca.gov/cc/scopingplan/submittals/agriculture/nrdc_biomethane_final.pdf.

Q3. What means beyond policies currently adopted by the two Commissions hold potential for the delivery of additional energy efficiency?

The following three policies offer the potential for the delivery of substantial additional energy efficiency resources within the 2020 timeframe. The first two of these policies were submitted by NRDC as recommendations to the CARB scoping plan process and we urge the Commissions to also consider these proposals in this proceeding.

Time-of-Sale Energy Efficiency Requirements

One of the key opportunities to make efficiency improvements in existing buildings is at the time the building is sold, since owners often have inspections of the property and make improvements as a result of a sale. Energy efficiency inspections, ratings, and improvements at the time of sale represent a significant opportunity to improve the existing building stock, since over 600,000 existing homes are sold each year, triple the number of new homes built. Time-of-sale information disclosure requirements, followed by time-of-sale efficiency requirements, should be adopted to ensure that this key opportunity to reduce GHG emissions is captured. We estimate that reductions of at least 3.1 $MMTCO_2E$ are possible by 2020. For further details, see NRDC's scoping plan recommendation. [11]

Urban Water Use Efficiency

Substantial amounts of energy are used throughout the state to treat, convey, and process water. By reducing end-uses of water, the associated embedded energy (and related GHG emissions) of water can also be reduced. We estimate that up to 4.8 $MMTCO_2E$ reductions could be achieved by 2020. [12] Electric and natural gas utilities can help increase water efficiency by partnering with water agencies to provide programs to customers.

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[11] Available at http://www.arb.ca.gov/cc/scopingplan/submittals/electricity/nrdc_time_of_sale_ee_final.pdf; http://www.arb.ca.gov/cc/scopingplan/submittals/electricity/nrdc_time_of_sale_ee_ghg_reduction_calcs.pdf.

[12] See NRDC's policy recommendations in our scoping plan proposed to CARB at http://www.arb.ca.gov/cc/scopingplan/submittals/electricity/nrdc_water_efficiency_final.pdf.

Natural Gas Infrastructure

The Commissions should consider instituting mandatory equipment updates and best management practices based on EPA's voluntary Energy STAR program for natural gas pipelines, storage facilities, and compressor stations.

Q4. What means beyond policies currently adopted by the two Commissions hold potential for the integration of additional renewable resources into the grid?

California should immediately adopt a 33% Renewables Portfolio Standard (RPS) to ensure the development of additional renewable resources to serve the state. The CEC Intermittency Analysis Project (IAP) concludes that the state's electricity system, if bolstered by transmission upgrades and prudent resource planning, can readily accommodate 33% renewables penetration with minor changes to system operation and infrastructure.[13] Establishing the 33% RPS in law provides market certainty that investors require to continue to invest in the development of renewable resources, and is therefore a necessary complement to any GHG cap-and-trade program. Establishing a 33% renewables requirement also provides clear direction to state agencies and retail providers to plan, site, and build transmission facilities to support higher penetrations of renewable energy. The policy certainty provided by a 33% RPS will further reinforce the goals and future findings of the recently established Renewable Energy Transmission Initiative (RETI), which should greatly improve the state's ability to access abundant renewable resources located in remote areas.

Q8. Provide feedback, as desired or appropriate, on the data sources used by E3 for its assumptions in its issue papers. If you prefer different assumptions or sources, provide appropriate citations and explain the reason for your preference.

Energy efficiency in the demand forecast

The E3 methodology assumes that the California Energy Commission's (CEC) demand forecast includes future or 'uncommitted' energy efficiency savings and therefore the E3 model does not include additional savings in the reference case. As a result, the analysis shows that the energy load in California is expected to increase on average by 1.2% per year.

[13] California Energy Commission 2007. *Intermittency Analysis Project*, CEC-500-2007-081.

In contrast, the recent CEC report *Achieving All Cost-Effective Energy Efficiency for California,* which analyzes the impact of achieving 100% of economic energy efficiency savings, does not assume that future or 'uncommitted' energy efficiency savings are embedded in the forecast. This alternative assumption results in a forecast of absolute reductions in consumption for the investor-owned utilities. This example highlights the importance of clarifying the actual amount of energy efficiency that is embedded within the CEC's demand forecast in order to accurately incorporate additional energy efficiency savings and forecast future demand.

In the CEC's recent *Integrated Energy Policy Report*, the CEC recognized the need to resolve this issue in an expedited manner, and committed to initiate a public process in early 2008 to determine an effective method of delineating the energy efficiency savings assumptions included in the CEC staff demand forecast.[14] NRDC urges the CPUC and E3 to participate in this process and to work closely with the CEC staff to resolve this issue.

Energy efficiency incentives and administrative costs

A second issue with respect to E3's assumptions is the level of incentive payment and administrative costs necessary to achieve very high levels of energy efficiency. In particular, E3 assumes that marginal incentive payments of up to 210% are needed to achieve 100% of economic potential. Moreover, E3 also assumes that administrative costs are a constant fraction (40%) of incremental costs. The high marginal incentive costs result in significant rate impacts, though TRC costs are not affected since incentives are considered a transfer payment in the TRC calculation. The high administrative costs increase both rates and TRC costs.

The assumptions adopted by E3 for incentive and administrative costs may represent a reasonable estimate of future costs assuming past program types. However, it seems likely that an aggressive effort to achieve 100% of economic potential will involve alternative programmatic approaches such as building codes, appliance standards, and upstream incentives that require lower incentive levels and administrative costs than

[14] California Energy Commission, *2007Integrated Energy Policy Report,* Publication 100-2007-008-CMF, December, 2007, p.93.

assumed by E3. We recognize and appreciate that the E3 model allows for the development of scenarios with alternative assumptions but believe that the values adopted by E3 for the baseline scenario are relatively high.

We recommend that E3 develop an alternative energy efficiency scenario based on a programmatic transition towards large upstream incentives (e.g. ~100% of incremental costs) followed relatively rapidly by the adoption of codes and standards. This approach could result in substantially lower incentives and administrative costs on a levelized basis than assumed in the aggressive efficiency scenario.

Efficiency in the WECC region

A key issue in the analysis of demand growth and energy efficiency is the amount of energy effficiency that will occur in the rest of the WECC region. While energy efficiency is analyzed as a key resource for California, it is completely absent for the rest of the region. Development of regional energy efficiency resources can benefit California by freeing up lower cost renewables and by reducing the price of natural gas.

In effect, the current model assumes no new efficiency resources in the WECC region outside of California. This is unlikely, because numerous states in the WECC have now committed to achieve economy-wide GHG emission reductions through the Western Climate Initiative and efficiency is the most cost-effective measure. While it would be possible to simulate regional energy efficiency programs in the E3 model by reducing the demand growth rates, this would fail to capture the cost savings of those programs and, in any case, would not be based on an assessment of the potential for efficiency gains. We recommend that a substantial effort be placed on developing an analysis of the regional energy efficiency resource, including estimates of BAU and aggressive scenario savings. The recent analysis of the impact of high energy efficiency savings across the WECC region that was conducted for the 2007 Integrated Energy Policy Report should provide a useful resource in developing this scenario.[15]

[15] "Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report," California Energy Commission, June 2007

Wind Integration Costs

A number of recent studies have found that in the range of 20-30% penetration, the integration costs of wind are $5-6/MWh.[16] Estimates of integration costs should reflect this conclusion. In contrast, the regression analysis method used by E3 leads to an estimated integration cost of $6.26-$9.39/MWh over a range of penetrations of 20-30%, which is a higher cost than that estimated by almost all previous wind integration studies. This high cost result is due in part to the inclusion of outdated data in the regression analysis, as further explained below. Of greater concern, however, is the fact that none of the studies included in the regression analysis are California-specific integration cost studies. The Intermittency Analysis Project (IAP), for instance, was funded by the CEC to estimate the impacts of integrating intermittent renewables in California. The results of the IAP indicate that the costs of additional load following in a high renewables penetration scenario are no greater than $0.48/MWh, and the costs of additional regulation are no greater than $0.22/MWh. The additional needs are based on various scenarios investigated in the IAP, including scenarios in which California achieves 33% renewable generation in-state.[17] These results were not used in the E3 regression analysis nor were the results of the regression compared with the results of the IAP as a benchmarking exercise.

The results of the E3 regression analysis are also skewed by the inclusion of outdated data. The Idaho Power integration study contains the highest integration costs of all the studies in the regression analysis, with costs that are considerably higher than any of the other studies at all levels of penetration. The integration costs numbers used in the E3 regression analysis were based on a February 2007 version of the Idaho Power study, which has since been substantially revised after the initial results were called into question. The integration model was revised to include an improved forecasting method,

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[16] Smith et al. 2007 "Best Practices in Grid Integration of Variable Wind Power: Summary of Recent US Case Study Results and Mitigation Measures" Presented at EWEC '07, Milan, Italy. May. The study states: "Wind integration studies have shown that wind integration costs of up to $5 to $6/MWh of wind energy can be expected for capacity penetrations of up to 20% to 30% of peak load." (page 8). Available at: http://www.uwig.org/EWEC07paper.pdf

[17] Porter, K. and Intermittency Analysis Project Team. 2007. Intermittency Analysis Project: Summary of Final Results. California Energy Commission, PIER Research Development & Demonstration Program. CEC-500-2007-081. Regulation costs: pg 186 of Appendix B, Load following costs: pg 182 of Appendix B.

to remove an artificial arbitrage opportunity that caused erroneous results, and to incorporate more reasonable assumptions for modeling reserve requirements.[18] The revised study estimates significantly lower integration costs over a wide range of wind penetration.[19] The updated results were released in October 2007 and should be used in the E3 regression analysis. Table 6 on page 30 of the revised Idaho Power report indicates that the updated results of the integration study correspond better with the rest of the integration studies in the E3 regression analysis. Furthermore, the increase in integration cost in the revised Idaho Power study is not proportional to the increase in wind penetration. Instead, the integration cost "curve" flattens at high wind penetrations, which is similar to the result of many of the other studies.

Another potential source of error in the E3 regression methodology is that a regression model was fit to data points pooled from many different studies. A more appropriate technique for estimating the coefficient for the increase in integration cost with increasing wind penetration may be to use the median of the slope from a regression fit to each individual study.

As a result, the wind integration cost assumptions used in the model should be revised to include updated information from the Idaho Power study and the CEC IAP. We also recommend applying a regression fit to the slope of each integration study; rather than the regression to the pooled data points used by E3. Making these changes will greatly improve the accuracy of the estimated wind integration costs in the model.

Wind Capacity Factors

The wind capacity factors used in the E3 model appear overly pessimistic. The E3 documentation of wind capacity factors states:

> The NREL model assigns a 40% average capacity factor to a reference plant in a Class 5 location. Other sources, including EIA, CEC, and AWEA, assign a 34% to 37% capacity factor for a Class 5 site. In the GHG calculator, the NREL capacity factors have been scaled downward to match the other data sources 34% capacity factor estimate for Class 5

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[18] Idaho Power. 2007 "Operational Impacts of Integrating Wind Generation into Idaho Power's Existing Resource Portfolio: Report Addendum" October. Available at: http://www.idahopower.com/pdfs/energycenter/wind/Addendum.pdf, p 20
[19] ibid. pg 2

resources… [New Wind Generation Resource, Cost, and Performance Assumptions, p. 3]

E3's decision to use the lowest estimate for a Class 5 capacity factor (34% in the stated range of 34-37%) as the base assumption for the E3 model is not justified in model documentation. A comparison of the estimates used in the E3 model to of the most widely used government and industry sources of wind capacity factors demonstrates that E3's capacity factor estimates are often substantially lower.

Comparison of Wind Capacity Factors Used in E3 GHG Model to a Variety of Other Sources

E3 GHG Model - Projections for 2020 [1]	Average Wind Projects First Online in 2004-2005 [2]	AEO 2007 [3]	NREL/ AWEA Wind Vision (2020) [4]
Class 3: 27.3%	Northwest - 31.5%		Class 3, 50m - 38%
Class 5: 34.0%	California - 34.2%		Class 5, 50m - 45%
Class 7: 40.0%	Mountain - 41.0%	"...a national average of 44 percent in the best wind class..."; "...assumed to be limited to about 48 percent for an average Class 6 site…"	Class 7, 50m - 52%

[1] E3 GHG Model: New Wind Generation Resource, Cost, and Performance Assumptions, pg 3
[2] U.S. DOE Annual Report on U.S.Wind Power Installation, Cost, and Performance Trends: 2006
[3] Assumptions to the Annual Energy Outlook 2007, Available at: http://www.eia.doe.gov/oiaf/aeo/assumption/renewable.html
[4] NREL/ AWEA Wind Vision Analysis, Supporting Documentation, Appendix B. Table 10, pg 15 (Forthcoming)

The table above indicates that the maximum wind capacity factor assumed for 2020 in the E3 model is even lower than the average capacity factor observed for wind plants that came online in 2004-2005 in the Mountain states of the U.S. The capacity factors used to characterize current and future wind turbine technology in the NREL/AWEA Wind Vision analysis ("Wind Vision") are also considerably higher than the capacity factors estimated by E3.[20] The assumed capacity factor in Wind Vision for a Class 5 resource at 50 m is 40% in 2005, increasing to 45% by 2020. Wind Vision assumes the capacity factors of Class 6 and 7 wind resources (common in areas like Wyoming) to be 44 - 47% in 2005, increasing to 48 - 52% by 2020. A 34% capacity factor, the capacity factor most frequently found in the E3 supply curve, applies only to a Class 3-4 resource in 2005.

[20] NREL/ AWEA Wind Vision Analysis, Supporting Documentation, Appendix B. Table 10, pg 15 (Forthcoming)

In light of these discrepancies, the wind capacity factor assumptions in the E3 model should be increased to be more consistent with the assumptions found in recent sources of wind capacity factor data.

Firming Penalty for Wind

We disagree with the firming cost terminology used in the E3 model and its associated documentation. The E3 model ascribes a "firming penalty" to different types of generating resources to account for their contribution to dependable capacity.[21] This is an incorrect and confusing use of the term, and implies the need to add generation to backup wind plants even though reliability can be maintained through minor changes to the existing electricity system. The word "firming" has been used in the California RPS program largely in the context of scheduling the output of out-of-state renewables for delivery and use in-state. To avoid creating unnecessary confusion over terms, "firming" should not be used for the purposes of ascribing capacity value to different types of generating resources.

The correct way to conceptualize the intermittency of wind and solar is on a system basis. Demand growth must be met with increases in the dependable capacity of generation resources. Flexible generation plants such as combustion turbines have a dependable capacity near 100% of their nameplate capacity that can contribute to meeting this capacity shortfall. Wind and other intermittent renewables provide relatively less effective capacity, and therefore do not contribute their full nameplate capacity toward meeting peak demand.

As such, it is accurate to discount the capacity value of wind and other intermittent renewables by applying a capacity value adjustment of some sort. This appropriately reflects the fact that a MW of nameplate capacity of wind will not help in meeting as much of system peak as one MW of a natural gas combustion turbine. However, the lower effective capacity of wind and other intermittent renewables does not require that the output of a new wind plant be "firmed."

[21] Attachment B at 148.

Transmission Costs

There are often substantial benefits that occur with transmission investments that extend to parties beyond the new generators and the customers that purchase the power. These benefits include deferment of other transmission investments, increased reliability, and reduced congestion. It is the role of the transmission operator to determine the beneficiaries of lines and share the costs accordingly.

E3's documentation of transmission costs is not entirely clear on how the transmission costs used in the model account for the potential benefits that the transmission investments will bring to other network users. For example, the CAISO study of transmission investments at Tehachapi indicates that a portion of the $1.8 billion transmission costs is for facilities that will defer other transmission investments required to meet load growth.[22] In the case of Tehachapi, the incremental transmission cost for the new facilities assigned to the Tehachapi resource zone in the E3 supply curve should only include the transmission cost above the transmission investment that would be required in any case due to load growth. Similarly, the NREL Wind Deployment System (WindDS) Model assumes that the costs of transmission upgrades for wind capacity additions are shared between load and new generation. WindDS assumes that generators are responsible for only 50% of the transmission upgrades required to support several thousand megawatts of new renewable development in the U.S.[23]

While a blanket assumption of 50% cost sharing between network users and generators may not be the appropriate methodology for the E3 model, it is not obvious what portion of the total cost of transmission upgrades are borne by new generation in the E3 model. The model documentation does not adequately explain how transmission investments are allocated between load and new generation. Instead, the methodology appears to assume that all new transmission investment only occurs to meet new generation requirements, implying that there would be no transmission investments if new generation were not built. We recommend E3 more clearly document assumptions

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[22] CAISO. (2006). *CAISO South Regional Transmission Plan for 2006 (CSRTP-2006) Part II: Findings and Recommendations on the Tehachapi Transmission Project.* Regional Transmission – South Planning and Infrastructure Development; California ISO. December. Available at: http://www.caiso.com/18db/18dbaedf2cca0.pdf (See pg 35 for summary of benefits of transmission upgrades)

[23] NREL/ AWEA Wind Vision Analysis, Supporting Documentation, Appendix B. pg 21 (Forthcoming)

underlying the allocation of new transmission investments in the model. Documentation of the methodology should also clearly state if in-state and out-of-state transmission is treated differently in terms of how transmission investment costs are allocated between new generators and the other network users.

Transmission costs for large additions of renewable energy have also been assessed in the IAP, which was not cited as a source for E3's estimates of transmission needs within California. Even if the E3 model does not rely on these transmission estimates, the costs of the transmission upgrades required to support new renewable development and the allocation of these costs should be benchmarked against the IAP results.

Finally, the nameplate capacity of the wind farm should not necessarily determine the rated capacity of a new transmission line, as the E3 model assumes. A number of simplified transmission cost studies for long transmission lines to renewable resource regions assume the nameplate capacity of the wind plants can be 20% greater than the rated capacity of the transmission line. The negative impact of "underutilizing" the transmission line on the amount of energy delivered is often outweighed by the cost savings from not over-sizing the transmission line.[24,25] We recommend that E3 consider a similar assumption for transmission lines to wind resource areas in its model.

Q9. Are uncertainties inherent in the resource potential and cost estimates adequately identified? Does E3's model provide enough flexibility to test alternative assumptions with respect to these uncertainties?

We are concerned that the E3 model does not account for the risks associated with different resource scenarios. In particular, California's heavy reliance on volatile natural gas prices carries significant and growing financial risks for customers. These risks should be reflected in the Commissions' GHG modeling efforts. Providing a single

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[24] For instance see: "Canada to Northern California Electric Transmission Line, WECC Regional Planning Project, Economic Analysis Committee, Benefit to Cost Ratio Screening Analysis" October 1st, 2007 p. 18. Available at: http://www.pge.com/includes/docs/pdfs/biz/transmission_services/canada/DRAFTEconomicAnalysisCommitteeReport.pdf

[25] Also see: Western Regional Transmission Expansion Partnership (WRTEP), Economic Analysis Subcommitee. 2007. Benefit-Cost Analysis of Frontier Line Possibilities. April. Available at: http://www.ftloutreach.com

deterministic cost estimate of each resource scenario fails to provide a complete picture of that scenario's costs, and thus provides incomplete information for the Commissions and the California Air Resources Board to determine GHG regulations for the electricity sector.

The California Energy Commission emphasizes the growing value of portfolio analysis in its latest Integrated Energy Policy Report ("IEPR"):

> Today's environment calls for an electric resource planning process that includes the variety of options, risks, and uncertainties that utilities must consider in evaluating potential resource additions. Choosing a resource addition based on current lowest-cost projections is no longer adequate if the potential for dramatically higher prices is ignored.[26]

A portfolio with the lowest projected cost may be much less preferable than a portfolio with slightly higher projected cost and much lower levels of risk. Using risk metrics to evaluate resource scenarios helps policymakers to weigh the tradeoffs between risk and cost. Risk analysis is particularly important in the context of GHG regulation, both because of the likely impact of GHG reduction measures on mitigating fuel price risk and the substantial uncertainty over the future cost of GHG emissions.

To reflect best modeling practices, the Commissions' GHG modeling efforts should incorporate risk metrics such as the year-to-year price variability associated with different modeling cases. At the very least, the Commissions' GHG modeling efforts should consider the effect of the variance of future natural gas prices on the variance of the cost estimates for each modeling case through 2020. For example, if the (purely hypothetical) range of natural gas prices within one standard deviation of the E3 forecast is $4.50 to $11.00/MMBtu, the GHG modeling should present the resulting range of cost and rate impacts for each modeling case. Because natural gas price uncertainty is typically the most important risk factor affecting overall portfolio risk, this would constitute a relatively quick and simple way to estimate the cost variability associated with different resource portfolios.

[26] California Energy Commission (CEC) 2007. *2007 Final Integrated Energy Policy Report*, p. 63.

Natural gas prices

In its current form, the E3 model does not account for the effect of increased reliance on preferred resources on reducing natural gas prices. Instead, the E3 model assumes that natural gas prices are unchanged between the reference and the target cases, even though natural gas demand may be much lower in the target case. The assumption that natural gas prices will not be affected by substantially reduced demand is a significant oversight of the E3 model.

Several studies have indicated that increasing the amount of energy efficiency and renewable energy in a system will decrease natural gas demand and natural gas prices.[27] Using two different models, the CEC's Scenario Analysis Project found that average wholesale natural gas prices in the WECC would decline by 15% in one model and 2% in another model under a scenario with high levels of efficiency and renewables throughout the West.[28] As the CEC Integrated Energy Policy Report ("IEPR") indicates, "Both these studies concluded that increasing energy efficiency and renewables in the electric sector reduces natural gas demand and may bring downward pressure on natural gas prices for all customers."[29]

Although the precise magnitude of the natural gas price reduction effect of increased resources is uncertain, there is little doubt that decreasing natural gas demand will also decrease natural gas prices. Even a modest decrease in natural gas prices of 2% would significantly improve the cost-effectiveness of GHG reduction strategies for both the electricity and natural gas sectors. Therefore, future modeling results should at the very least include sensitivity scenarios in which the natural gas demand reductions induced by increased reliance on preferred resources are reflected in reduced natural gas prices.

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[27] For an overview of the existing literature on the subject, see: Wiser, R. and M. Bolinger 2007. "Can Deployment of Renewable Energy and Energy Efficiency Put Downward Pressure on Natural Gas Prices?" *Energy Policy*, 35(1).
[28] California Energy Commission (CEC) 2007. *2007 Final Integrated Energy Policy Report*, p. 237.
[29] Ibid.

Q12. What specific flexible GHG emission reduction mechanisms to mitigate the economic impacts of achieving the desired GHG emissions reductions should be modeled in Stage 2?

We assume that this question asks about possible flexible *compliance* mechanisms, as we are unclear as to what "flexible emission reduction mechanisms" would entail. We suggest the following flexible compliance mechanisms be modeled in Stage 2 of E3's modeling efforts:

- Trading of allowances between parties
- Multi-year compliance periods (e.g., 3 years)
- Banking of allowances from one compliance period to the next

Q13. What output metric or metrics should be utilized to evaluate the least cost way to meet a 2020 emission reduction target for the sector?

Policy makers have been asked to develop a comprehensive and effective strategy to reduce GHG emissions from the energy sectors. This strategy will likely include a variety of programs and policies and will need to be both reliable and cost-effective. The output metrics from this model should be designed to support the decision-making process necessary to adopt these policies.

We believe that the E3 model results are an excellent start but that they do not yet provide adequate information to support policymakers. A principal focus of this effort over the next few months should be an expansion of the E3 model to include both additional outputs and additional scenarios. As detailed below, the model outputs should include systemwide cost and benefit estimates under different emissions targets, emissions reductions at different costs, information on the costs and impacts of different policies, and an analysis of key risks and uncertainties.

In particular, we recommend that the CPUC GHG modeling effort should be expanded to provide the following information:

- All output metrics for reducing emissions of each sector: 1) back to its own 1990 levels; and 2) by 29% below 2020 business as usual levels.

- Total emission reductions in 2020 and all output metrics for a range of marginal and average emission reduction costs, e.g. $100 per ton, $150 per ton, $200 per ton, etc. Particularly useful would be a supply curve of emissions reductions (i.e. a plot of emissions reductions vs costs).
- Summary information should be broken out to provide results for the electric sector, natural gas sector, and combined energy sector.
- An analysis of the variability associated with natural gas prices and other key assumptions and uncertainties. This analysis should include, at a minimum, the impact of emission reductions policies on costs and rates at a range of potential natural gas prices.
- An analysis of key policies that might be implemented including a 33% RPS and a regional efficiency initiative. This might include an analysis of the impact of different targets with and without these policies.
- The impact of a set of flexible compliance mechanisms including allowance trading, banking, and multi-year compliance periods.

The output metrics should be geared towards answering the key questions policymakers will need to consider, including the following for each scenario:

- What level of GHG emissions is reached in 2020? How does this compare to the sector's 1990 emissions, 2008 emissions, and 2020 BAU levels? What is the trajectory from 2012 to 2020?
- What is the total costs/savings of the investments relative to business as usual?
- What will rates be in 2020? What is the rate increase/decrease relative to business as usual? What is the total and incremental *annual* rate increase/decrease necessary to get there?
- How does the riskiness of the portfolio compare to business as usual (e.g., how does the variability in customers' costs change if gas prices were one standard deviation above or below the estimated value)?
- What is the average cost per ton of all measures (including existing EE and renewables) used to reduce GHGs in the sector?

- What is the market price of allowances (i.e., what is the marginal cost per ton) every year from 2012 to 2020?

The E3 summary tables currently provide some of this information, and we urge the Commission to work closely with E3 to develop the output metrics and summary information that will be most useful in answering these questions. For example, the summary table currently provides the total GHG emissions for the scenario, BAU, and 2008 levels. We recommend that this be expanded to show GHG emissions for 1990 levels and 29% below BAU for comparison purposes, and to provide more detailed graphs that split out the electric and gas sector information.

We also urge E3 to provide more information about cost-effectiveness. For example, the summary should include the average cost per ton of GHG emissions reduced, including all of the existing measures such as EE that provide significant cost savings. This will help provide a more complete picture of the utility sector costs for when CARB compares them to other sectors. The summary should also include the marginal cost per ton that might be expected under a cap and trade program. And E3 should clearly explain how sensitive the estimates of cost-effectiveness are to the BAU assumptions, since the tons "reduced" change dramatically depending on whether a measure is assumed to be reducing emissions associated with, for example, a combined cycle natural gas plant versus a conventional coal fired plant. In addition, the summaries for the demand side activities should clearly show the cost savings that are coming from energy efficiency. Finally, all model outputs should be clearly labeled and defined to avoid confusion.[30]

[30] For example, the summary results in the current draft includes both total producer costs (as a dollar figure) and total system costs (relative to 2008 and the reference scenario in the bar chart) without clearly identifying the differences between the two estimates.

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the **"Comments of the Natural Resources Defense Council (NRDC) and the Union of Concerned Scientists (UCS) on Modeling-Related Issues in the matter of R.06-04-009** to all known parties of record in this proceeding by delivering a copy via email or by mailing a copy properly addressed with first class postage prepaid.

Executed on January 4, 2008 at San Francisco, California.

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